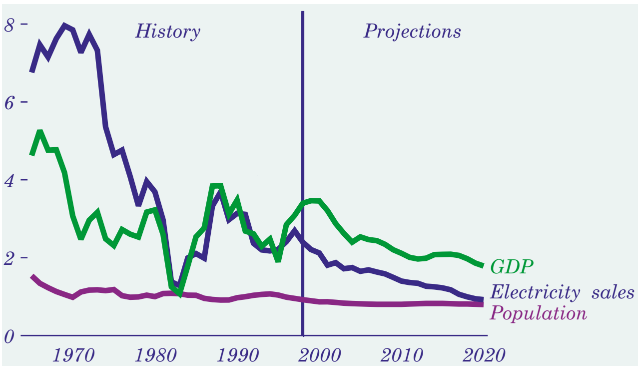
Parallel Growth Rates Are Projected for Electricity Use and GDP

Figure 66. Population, gross domestic product, and electricity sales, 1965-2020 (5-year moving average annual percent growth)



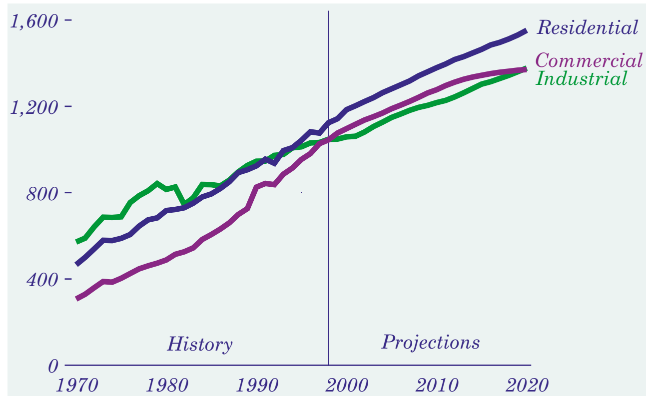
As generators and cogenerators try to adjust to the evolving structure of the electricity market, they also face slower growth in demand than in the past. Historically, the demand for electricity has been related to economic growth. That positive relationship is expected to continue, but the ratio is uncertain.

During the 1960s, electricity demand grew by more than 7 percent a year, nearly twice the rate of economic growth (Figure 66). In the 1970s and 1980s, however, the ratio of electricity demand growth to economic growth declined to 1.5 and 1.0, respectively. Several factors have contributed to this trend, including increased market saturation of electric appliances, improvements in equipment efficiency and utility investments in demand-side management programs, and more stringent equipment efficiency standards. Throughout the forecast, growth in demand for office equipment and personal computers, among other equipment, is dampened by slowing growth or reductions in demand for space heating and cooling, refrigeration, water heating, and lighting. The continuing saturation of electricity appliances, the availability and adoption of more efficient equipment, and efficiency standards are expected to hold the growth in electricity sales to an average of 1.4 percent a year between 1998 and 2020, compared with 2.2-percent annual growth in GDP.

Changing consumer markets could mitigate the slowing of electricity demand growth seen in these projections. New electric appliances are introduced frequently. If new uses of electricity are more substantial than currently expected, they could offset future efficiency gains to some extent.

Continued Growth in Electricity Use Is Expected in All Sectors

Figure 67. Annual electricity sales by sector, 1970-2020 (billion kilowatthours)



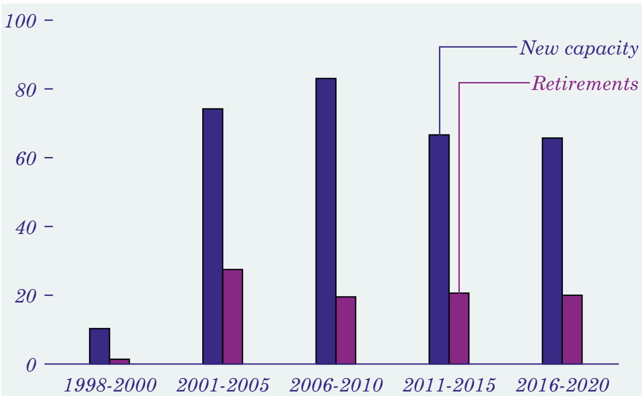
With the number of U.S. households projected to rise by 1.0 percent a year between 1998 and 2020, residential demand for electricity grows by 1.5 percent annually (Figure 67). Residential electricity demand changes as a function of the time of day, week, or year. During summer, residential demand peaks in the late afternoon and evening, when household cooling and lighting needs are highest. This periodicity increases the peak-to-average load ratio for local utilities, which rely on quick-starting gas turbines or internal combustion engines to satisfy peak demand. Although many regions currently have surplus baseload capacity, strong growth in the residential sector will result in a need for more "peaking" capacity. Between 1998 and 2020, generating capacity from gas turbines and internal combustion engines is expected to more than triple.

Electricity demand in the commercial and industrial sectors grows by 1.2 and 1.3 percent a year, respectively, between 1998 and 2020. Annual commercial floorspace growth of 0.9 percent and industrial output growth of 1.8 percent contribute to the increase.

In addition to sectoral sales, cogenerators in 1998 produced 165 billion kilowatthours for their own use in industrial and commercial processes, such as petroleum refining and paper manufacturing. By 2020, cogenerators are expected to see only a slight decline in their share of total generation, increasing their own-use generation to 184 billion kilowatthours as the demand for manufactured products increases.

Retirements of Nuclear Capacity Could Lead to Higher Fossil Fuel Use

Figure 68. New generating capacity and retirements, 1998-2020 (gigawatts)



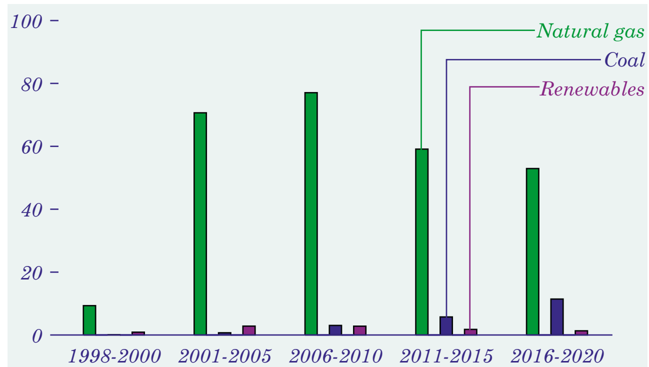
Despite slower demand growth, 300 gigawatts of new generating capacity will be needed by 2020 to meet growing demand and to replace retiring units. Between 1998 and 2020, 40 gigawatts (41 percent) of current nuclear capacity and 28 gigawatts (16 percent) of current oil- and gas-fired fossil-steam capacity [*65*] are expected to be retired. Of the 132 gigawatts of new capacity needed after 2010 (Figure 68), 21 percent will replace retired nuclear capacity.

The reduction in baseload nuclear capacity has a marked impact on the electricity outlook after 2010: 46 percent of the new combined-cycle and 82 percent of the new coal-fired capacity projected in the entire forecast are brought on line between 2010 and 2020. Before the advent of natural gas combined-cycle plants, fossil-fired baseload capacity additions were limited primarily to pulverized-coal steam units; however, efficiencies for combined-cycle units are expected to approach 54 percent by 2010, compared with 49 percent for coal-steam units, and the construction costs for combined-cycle units are only about 41 percent of those for coal-steam plants.

As older nuclear power plants age and their operating costs rise, more than 40 percent of currently operating nuclear capacity is expected to retire by 2020. More optimistic assumptions about operating lives and costs for nuclear units would reduce the need for new fossil-based capacity and reduce fossil fuel prices.

A Thousand New Generating Plants Could Be Needed by 2020

Figure 69. Electricity generation and cogeneration capacity additions by fuel type, 1998-2020 (gigawatts)

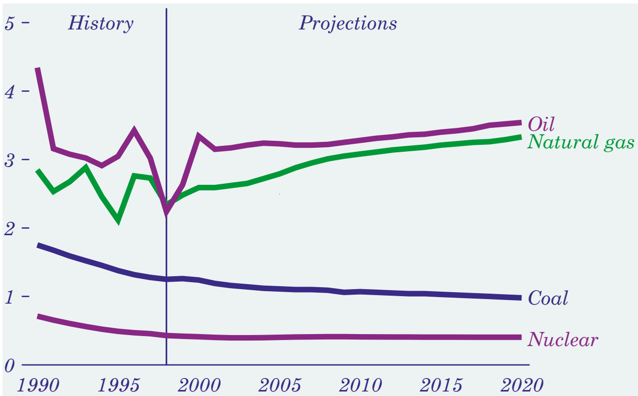


Before building new capacity, utilities are expected to use other options to meet demand growth—maintenance of existing plants, power imports from Canada and Mexico, and purchases from cogenerators. Even so, assuming an average plant capacity of 300 megawatts, a projected 1,000 new plants with a total of 300 gigawatts of capacity will be needed by 2020 to meet growing demand and to offset retirements. Of the new capacity, 90 percent is projected to be combined-cycle or combustion turbine technology fueled by natural gas or both oil and gas (Figure 69). Both technologies are designed primarily to supply peak and intermediate capacity, but combined-cycle technology can also be used to meet baseload requirements.

More than 21 gigawatts of new coal-fired capacity is projected to come on line between 1998 and 2020, accounting for almost 7 percent of all capacity expansion. Competition with low-cost gas-turbine-based technologies and the development of more efficient coal gasification systems have compelled vendors to standardize designs for coal-fired plants in efforts to reduce capital and operating costs in order to maintain a share of the market. Renewable technologies account for the remaining 3 percent of capacity expansion by 2020—primarily wind, biomass gasification, and municipal solid waste units. Oil-fired steam plants, with higher fuel costs and lower efficiencies, account for very little of the new capacity in the forecast. By 2020, annual investment in new capacity will be nearly $30 billion, assuming that the cost of new plants is recovered over a 20-year period.

Competition Is Expected To Reduce Electricity Generation Costs

Figure 70. Fuel prices to electricity generators, 1990-2020 (1998 dollars per million Btu)

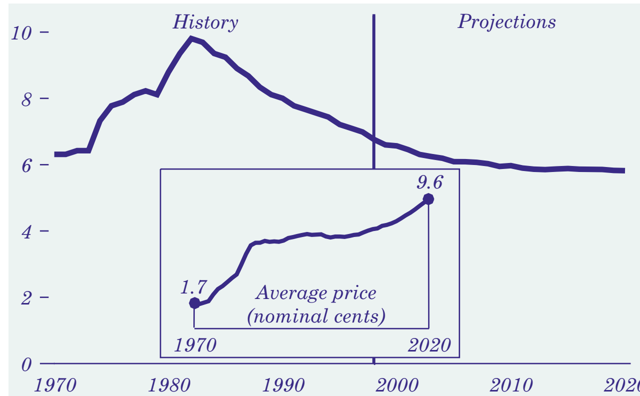


The cost of producing electricity is a function of fuel costs, operating and maintenance costs, and the cost of capital. In 1998, fuel costs for existing fossil plants typically represented $23 million annually—or 78 percent of the total operational costs (fuel and operating and maintenance)—for a 300-megawatt coal-fired plant, and $30 million annually—or 85 percent of the total operational costs—for a gas-fired combined-cycle plant of the same size. For nuclear plants, fuel costs are typically a much smaller portion of total production costs. Nonfuel operations and maintenance costs are a larger component of the operating costs for nuclear power plants than for fossil plants.

Over the projection period, the impact of rising gas prices is expected to be more than offset by the combination of falling coal prices and stable nuclear fuel costs. Natural gas prices to electricity suppliers rise by 1.6 percent a year in the forecast, from $2.40 per thousand cubic feet in 1998 to $3.41 in 2020 (Figure 70). Those increases are offset by declining coal prices, declining capital expenditures, and improved efficiencies for new plants. Sufficient supplies of uranium and fuel processing services are expected to keep nuclear fuel costs around $0.40 per million Btu (roughly 4 mills per kilowatthour) through 2020. Oil prices to utilities are expected to increase by 2.1 percent a year, leading to a decline in oil-fired generation of nearly 64 percent between 1998 and 2020. Oil currently accounts for only 3.4 percent of total generation, however, and that share is expected to decline to 0.9 percent by 2020 as oil-fired steam generators are replaced by gas turbine technologies.

Competitive Generation Markets Should Narrow Price Differences

Figure 71. Average U.S. retail electricity prices, 1970-2020 (1998 cents per kilowatthour)



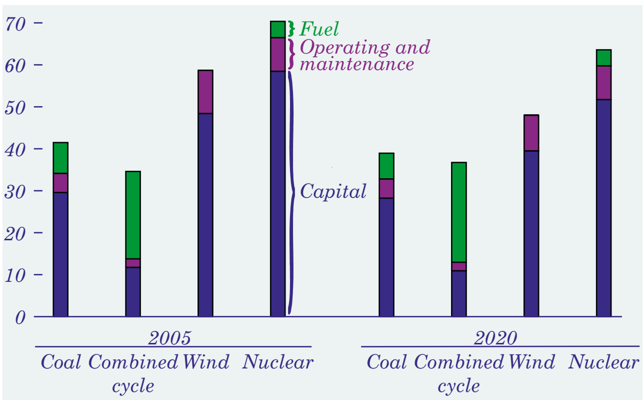
Between 1998 and 2020, the average price of electricity in real 1998 dollars is projected to decline by 0.6 percent a year as a result of competition among electricity suppliers (Figure 71). By sector, projected prices in 2020 are 10, 17, and 14 percent lower than 1998 prices for residential, commercial, and industrial customers, respectively.

The reference case assumes a transition to competitive pricing in five regions—California, New York, New England, the Mid-Atlantic Area Council (consisting of Pennsylvania, Delaware, New Jersey and Maryland), and Texas. In addition, prices in the Rocky Mountain Power Area/Arizona, the Mid-America Interconnected Network (consisting of Illinois and parts of Wisconsin and Missouri), and the East Central Area Reliability Council are treated as partially competitive, because some of the States in those regions have begun to deregulate their markets.

Specific restructuring plans differ from State to State and utility to utility, but most call for a transition period during which customer access will be phased in. The transition period reflects the time needed for the establishment of competitive market institutions and the recovery of stranded costs as permitted by regulators. It is assumed that competition will be phased in between 1999 and 2007, with fully competitive prices beginning in 2008. In all the competitively priced regions, the generation price is set by the marginal cost of generation. Transmission and distribution prices are assumed to remain regulated.

Least Expensive Technology Options Are Likely Choices for New Capacity

Figure 72. Electricity generation costs, 2005 and 2020 (1998 mills per kilowatthour)



Technology choices for new generating capacity are made to minimize cost while meeting local and Federal emissions constraints. The choice of technology for capacity additions is based on the least expensive option available (Figure 72). The reference case assumes a capital recovery period of 20 years. In addition, the cost of capital is based on competitive market rates, to account for the competitive risk of siting new units.

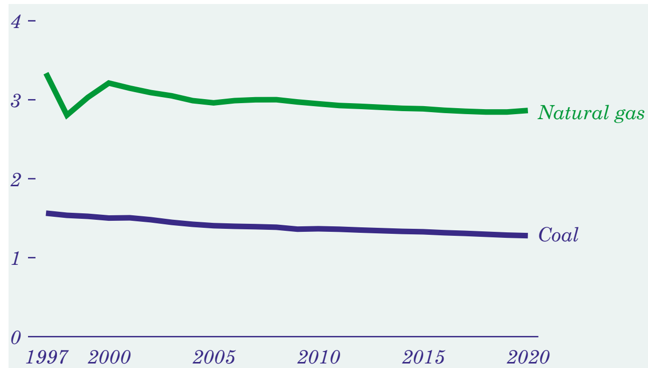
In the *AEO2000* projections, the costs and performance characteristics for new plants improve over time, at rates that depend on the current stage of development for each technology. For the newest technologies, capital costs are initially adjusted upward to reflect the optimism inherent in early estimates of project costs. As project developers gain experience, the costs are assumed to decline. The decline continues at a slower rate as more units are built. The performance (efficiency) of new plants is also assumed to improve, with heat rates declining by 5 to 18 percent between 1998 and 2010, depending on the technology (Table 9).

Table 9. Costs of producing electricity from new plants, 2005 and 2020

Item	2005 Advanced coal	2005 Advanced combined cycle	2020 Advanced coal	2020 Advanced combined cycle
	1998 mills per kilowatthour			
Capital	29.58	11.76	28.24	10.94
O&M	4.58	2.03	4.58	2.03
Fuel	7.32	20.82	6.12	23.77
Total	**41.48**	**34.61**	**38.94**	**36.74**
	Btu per kilowatthour			
Heat rate	9,253	6,639	9,087	6,350

Power Plant Operating Costs Are Expected To Continue Declining

Figure 73. Average operating costs for coal- and gas-fired generating plants, 1997-2020 (1998 cents per kilowatthour)

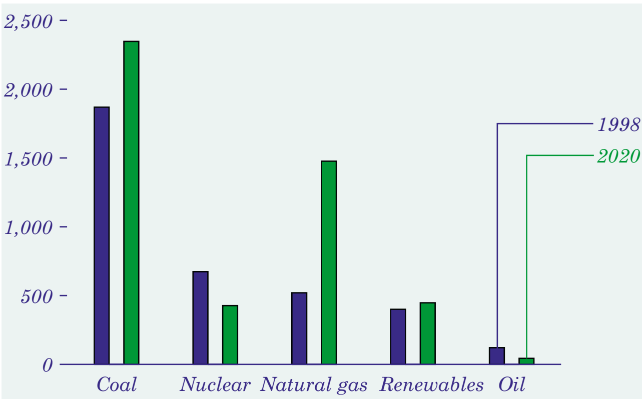


Since 1980, the per-kilowatthour operating costs for gas-fired and, particularly, coal-fired power plants have fallen significantly (Figure 73). For coal plants, fuel prices have been declining since the early 1980s. For gas plants, fuel prices rose in the early 1980s but declined sharply in 1986. Generating costs for coal-fired plants fell by 49 percent from 1980 to 1996, and the costs for gas-fired plants, even with the price increase that occurred in 1996, were still 24 percent lower than their peak in 1984.

The trend of declining costs for coal-fired plants is expected to continue as coal prices continue falling. In addition, nonfuel operations and maintenance costs are also expected to fall. In 1982, coal-fired steam plants used 250 employees per gigawatt of installed capacity, but utilities were able to reduce that number to 200 by 1995. Efforts to cut staff and reduce operating costs were prompted by the combination of technology improvements and competitive pressure. The amount by which utilities can continue to cut costs is uncertain, but many analysts agree that further reductions are possible. For gas-fired plants, per-kilowatthour generating costs are expected to fall early in the projections before leveling off. Although natural gas prices are expected to increase, the fuel costs per kilowatthour for gas-fired power plants are projected to remain steady as the efficiencies of new plants improve, offsetting the rise in fuel prices.

Gas- and Coal-Fired Generation Grows as Nuclear Plants Are Retired

Figure 74. Electricity generation by fuel, 1998 and 2020 (billion kilowatthours)



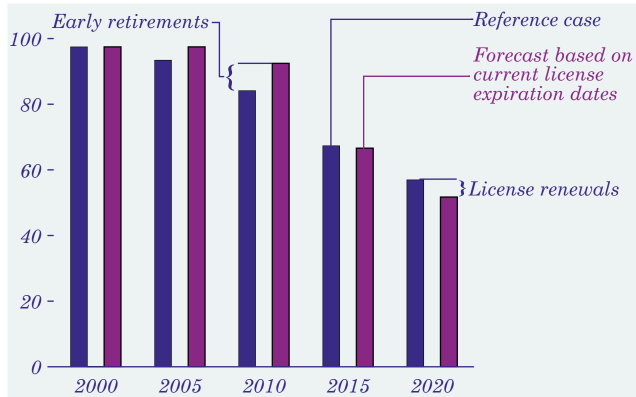
As they have since early in this century, coal-fired power plants are expected to remain the key source of electricity through 2020 (Figure 74). In 1998, coal accounted for 1,869 billion kilowatthours or 52 percent of total generation. Although coal-fired generation is projected to increase to 2,347 billion kilowatthours in 2020, increasing gas-fired generation reduces coal's share to 49 percent. Concerns about the environmental impacts of coal plants, their relatively long construction lead times, and the availability of economical natural gas make it unlikely that many new coal plants will be built before about 2005. Nevertheless, slow growth in other generating capacity, the huge investment in existing plants, and increasing utilization of those plants will keep coal in its dominant position. By 2020, it is projected that 21 gigawatts of coal-fired capacity will be retrofitted with scrubbers to meet the requirements of the Clean Air Act Amendments of 1990 (CAAA90).

The large investment in existing plants will also make nuclear power a growing source of electricity at least through 2000. Because the recent performance of nuclear power plants has improved substantially, nuclear generation is projected to increase until 2000, then decline as older units are retired.

In percentage terms, gas-fired generation shows the largest increase, from 14 percent of the 1998 total to 31 percent in 2020. As a result, by 2005, natural gas overtakes nuclear power as the Nation's second-largest source of electricity. Generation from oil-fired plants remains fairly small throughout the forecast.

Some Nuclear Plants Are Expected To Operate Past Current License Dates

Figure 75. Nuclear capacity and license expiration dates, 2000-2020 (gigawatts)

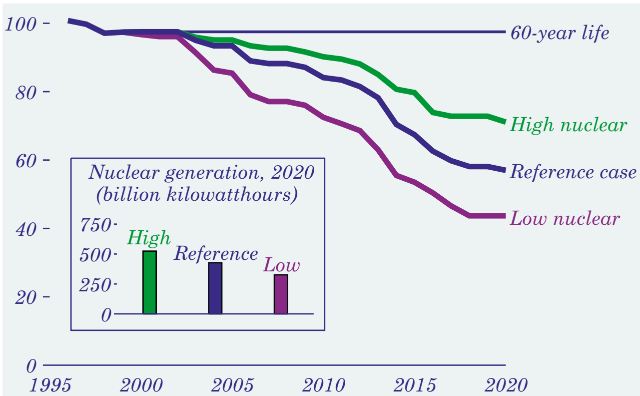


The United States currently has 104 operable nuclear units, which provided 19 percent of total electricity generation in 1998. In the reference case, 41 percent of current nuclear capacity is expected to be taken out of service by 2020, as operating licenses expire or units are retired early. Early retirements are based on the assumption that major aging-related investments will be needed after 30 years of operation and will be made only if they are more economical than building new capacity. Thirteen nuclear units are projected to be retired early in the reference case. No new nuclear units are expected to become operable by 2020, because natural gas and coal-fired plants are projected to be more economical.

Although some nuclear units are expected to be retired before the expiration of their 40-year operating licenses, others are expected to operate longer than their current license terms. Utilities for 2 plants have submitted license renewal applications with the Nuclear Regulatory Commission, and as many as 12 more are scheduled to apply over the next 4 years. The forecast assumes that plants will continue to operate if further investments to combat aging effects after 40 and 50 years are more economical than building new capacity. The reference case projects that 12 units with license expiration dates before 2020 will continue operating after license renewals; as a result, the projections show more nuclear capacity on line in 2020 than would be operable if all units were retired at license expiration (Figure 75).

Nuclear Power Could Be Key to Reducing Carbon Emissions

Figure 76. Operable nuclear capacity in three cases, 1996-2020 (gigawatts)

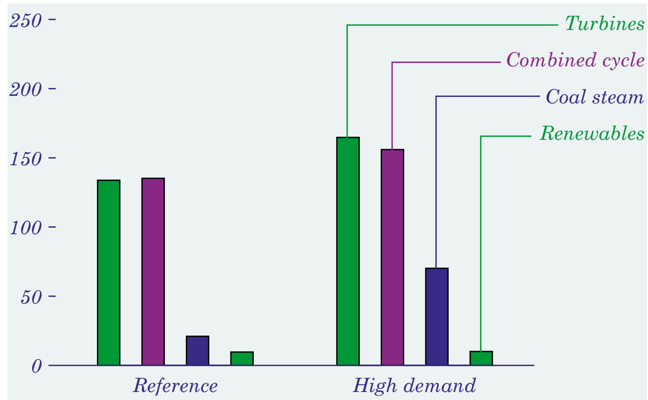


Two alternative cases—the high and low nuclear cases—show how nuclear plant retirement decisions affect the projections for capacity. If each plant operating today were able to operate for 20 years beyond its current license expiration date, nuclear capacity in 2020 would remain at the 1998 level (Figure 76). The high nuclear case assumes that the capital expenditures required after 40 years will be lower than in the reference case, and that more license renewals will be obtained by 2020. Conditions favoring license renewal could include performance improvements, a solution to the waste disposal problem, or stricter limits on emissions from fossil-fired generating facilities. The low nuclear case assumes that the capital expenditures required for continued operation are higher than assumed in the reference case, leading to the retirement of 15 additional units by 2020. Higher costs could result from more severe degradation of the units or from waste disposal problems.

In the high nuclear case, 16 gigawatts of new fossil-fired capacity would not be needed, as compared with the reference case, and carbon emissions would be reduced by 5 million metric tons in 2010 and 14 million metric tons in 2020 (2 percent of total emissions by electricity generators). In the low nuclear case, more than 44 new fossil-fired units (assuming an average size of 300 megawatts) would be built to replace additional retiring nuclear units. The new capacity would be split between coal-fired units (25 percent) and combined-cycle units (75 percent). The additional fossil-fueled capacity would produce 15 million metric tons of carbon emissions above those in the reference case in 2020.

High Demand Assumption Leads to Higher Fuel Prices for Generators

Figure 77. Cumulative new generating capacity by type in two cases, 1998-2020 (gigawatts)



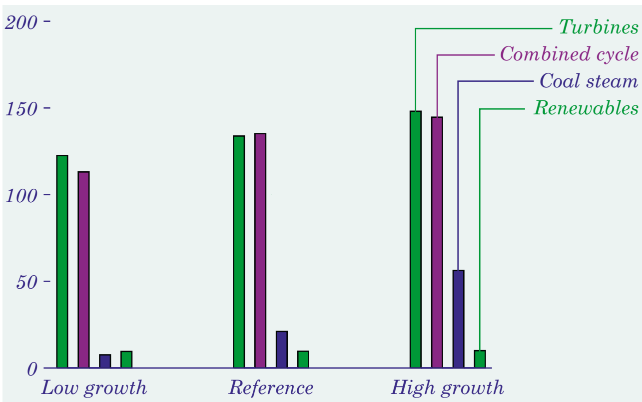
Electricity consumption grows in the forecast, but the rate of increase lags behind historical levels as a result of assumptions about efficiency improvements in end-use technologies, demand-side management programs, and population and economic growth. Deviations from the assumptions could result in substantial changes in electricity demand. In a high demand case, electricity demand is assumed to grow by 2.0 percent a year between 1998 and 2020, comparable to the growth rate of 2.2 percent a year between 1990 and 1998. In the reference case, electricity demand is projected to grow by 1.4 percent a year.

In the high demand case, an additional 101 gigawatts of new generating capacity—equivalent to 337 new 300-megawatt generating plants—is built between 1998 and 2020 as compared with the reference case (Figure 77). The shares of coal- and gas-fired (including non-coal steam, combustion turbine, combined cycle, and fuel cell) capacity additions change slightly: by 7 percent and 90 percent, respectively, in the reference case and by 18 percent and 80 percent in the high demand case. Relative to the reference case, there is a 13-percent increase in coal consumption and a 15-percent increase in natural gas consumption in the high demand case, and carbon emissions are 115 million metric tons (13 percent) higher.

More rapid growth in electricity demand also leads to higher prices. The price of electricity in 2020 is 6.5 cents per kilowatthour in the high demand case, compared with 5.8 cents in the reference case. Higher fuel prices, especially for natural gas, are the primary reason for the difference.

Rapid Economic Growth Would Boost Advanced Coal-Fired Capacity

Figure 78. Cumulative new generating capacity by type in three cases, 1998-2020 (gigawatts)



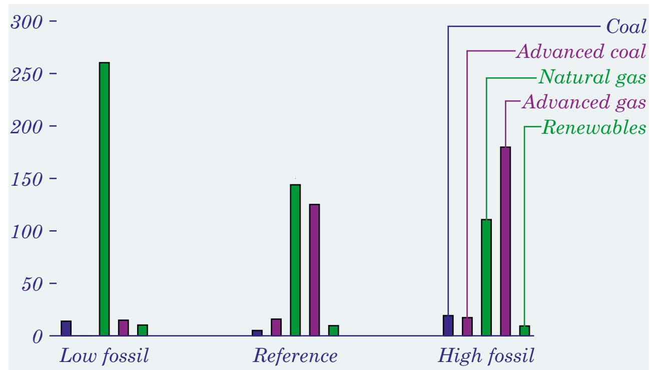
The annual average growth rate for GDP from 1998 to 2020 ranges from 2.6 percent in the high economic growth case to 1.7 percent in the low economic growth case. The difference of a percentage point in the economic growth rate leads to a 12-percent change in electricity demand in 2020, with a corresponding difference of 107 gigawatts of new capacity required in the high and low economic growth cases. Utilities are expected to retire about 12 percent of their current generating capacity (equivalent to 300 300-megawatt generating plants) by 2020 as the result of increased operating costs for aging plants.

Most of the new capacity needed in the high economic growth case beyond that added in the reference case is expected to consist of new advanced coal-fired plants, which make up more than 59 percent of the projected new capacity in the high growth case. The stronger growth also stimulates additions of gas-fired plants, which account for 40 percent of the capacity increase in the high economic growth case over that projected in the reference case (Figure 78).

Current construction costs for a typical plant range from $450 per kilowatt for combined-cycle technologies to $1,100 per kilowatt for coal-steam technologies. Those costs, along with the difficulty of obtaining permits and developing new generating sites, make refurbishment of existing power plants a profitable option in some cases. Between 1998 and 2020, utilities are expected to maintain most of their older coal-fired plants while retiring many of their older, higher cost oil- and gas-fired generating plants.

Gas-Fired Technologies Lead New Additions of Generating Capacity

Figure 79. Cumulative new electricity generating capacity by technology type in three cases, 1998-2020 (gigawatts)

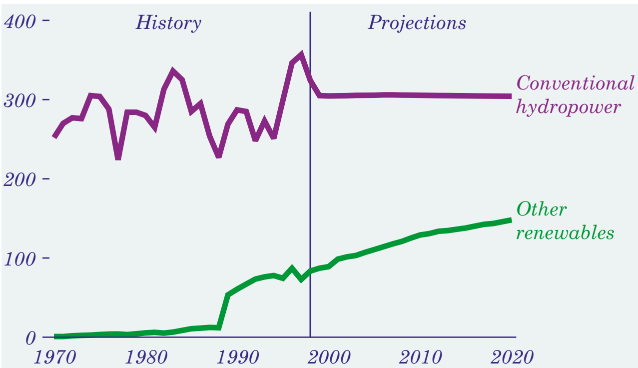


The *AEO2000* reference case uses the cost and performance characteristics of generating technologies to select the mix and amounts of new generating capacity for each year in the forecast. Numerical values for the characteristics of different technologies are determined in consultation with industry and government specialists. In the high fossil fuel case, capital costs, operating costs, and heat rates for advanced fossil-fired generating technologies (integrated coal gasification combined cycle, advanced combined cycle, advanced combustion turbine, and molten carbonate fuel cell) were revised to reflect potential improvements in costs and efficiencies as a result of accelerated research and development. The low fossil fuel case assumes that no advanced technologies will come on line during the projection period.

The basic story is the same in each of the three cases—gas technologies are expected to dominate new generating capacity additions (Figure 79). Across the cases the share of additions accounted for by gas technologies varies from 86 percent to 92 percent, and the mix between current and advanced gas technologies also varies across the cases. In the low fossil fuel case only 5 percent (15 gigawatts) of the gas plants added are advanced technology facilities, as compared with a 62-percent share (180 gigawatts) in the high fossil fuel case. Additions of coal-fired capacity increase slightly in the high fossil fuel case, but there is little change in additions of new renewable plants across the cases.

Renewable Generation Is Constrained by Relatively High Costs

Figure 80. Grid-connected electricity generation from renewable energy sources, 1970-2020 (billion kilowatthours)

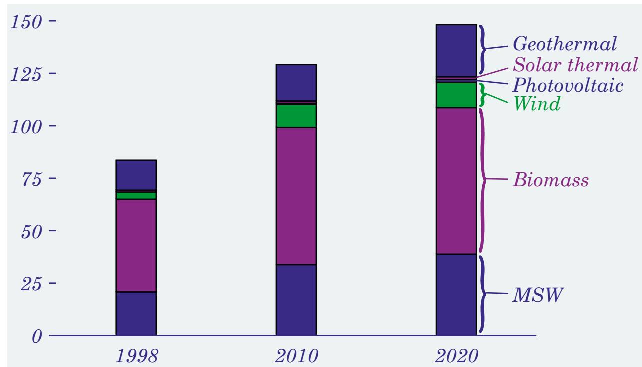


In the *AEO2000* reference case, projections are mixed for renewables in central station grid-connected U.S. electricity supply. State mandates produce substantial near-term growth for some renewable energy technologies, but generally higher costs are a disadvantage for renewables relative to fossil-fueled technologies over the forecast period as a whole. Total U.S. grid-connected electricity generation from renewable energy sources increases from 408 billion kilowatthours in 1998 to 452 billion kilowatthours in 2020, and generation from renewables other than hydroelectricity increases from 84 billion kilowatthours to 148 billion kilowatthours (Figure 80). Overall, renewables are projected to make up a smaller share of U.S. electricity generation, declining from 11.3 percent in 1998 to 9.5 percent in 2020.

Conventional hydroelectricity, which currently accounts for 80 percent of the electricity supply from renewables, declines slightly in the forecast. The expected addition of 620 megawatts of new capacity does not offset declines from existing hydroelectric facilities, as increasing environmental and other competing needs reduce their average productivity, and hydroelectric generation slips from 9.0 percent of the U.S. total in 1998 to 6.4 percent in 2020. The economic value of hydroelectric capacity is also likely to decline as environmental preferences shift generation to off-peak hours and seasons. If new legislation not assumed in the forecasts facilitates the removal of existing dams, hydroelectric generation will decline more sharply.

MSW and Biomass Lead the Increase in Renewable Fuel Use for Electricity

Figure 81. Nonhydroelectric renewable electricity generation by energy source, 1998, 2010, and 2020 (billion kilowatthours)



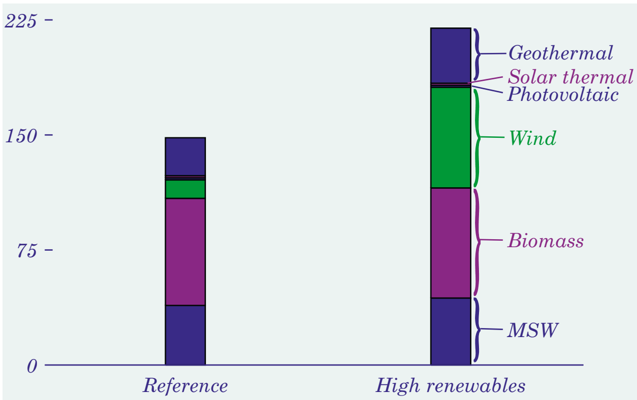
Most of the projected growth in renewable electricity generation is attributed to biomass, municipal solid waste (MSW), geothermal energy, and wind power (Figure 81). Generation from biomass and MSW increases the most, from a combined total of 65 billion kilowatthours in 1998 to 109 billion in 2020. Generation from biomass, particularly in the pulp and paper industries, grows by nearly 26 billion kilowatthours through 2020, more than half of which is from industrial cogeneration and the remainder either from plants using biomass strictly for electricity generation or from biomass co-firing in coal-fired plants, as co-firing is used increasingly to reduce emissions. Dedicated biomass-consuming capacity, with higher capital and fuel costs than fossil-fueled technologies, increases by only 1.2 gigawatts.

U.S. wind-powered generating capacity increased by a total of nearly 860 megawatts in 1998 and 1999, spurred by the now-expired Federal production tax credit. State mandates are estimated to yield nearly 2,400 megawatts of additional new wind capacity from 1999 through 2010, and more than 400 additional megawatts through 2020. Nevertheless, higher capital costs, lower output per kilowatt, and limited predictability put wind power at a disadvantage relative to natural gas and coal technologies.

Geothermal energy capacity is projected to increase by 860 megawatts between 1998 and 2020, contributing an additional 10 billion kilowatthours of generation in 2020. Solar technologies are not expected to add significantly to central station power generation, but off-grid and distributed applications for photovoltaics should continue robust growth.

Wind Energy Use Would Gain Most From Cost Reductions

Figure 82. Nonhydroelectric renewable electricity generation in two cases, 2020 (billion kilowatthours)



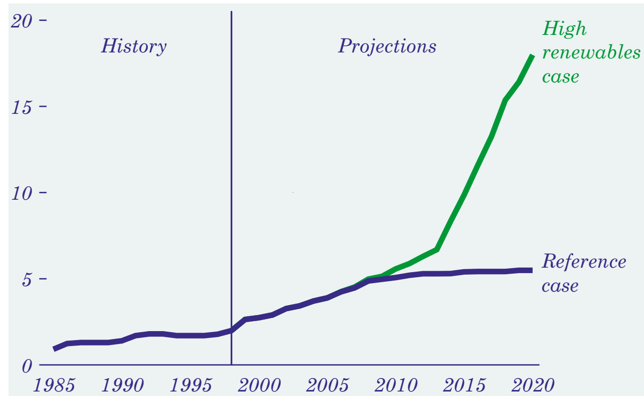
The *AEO2000* high renewables case assumes markedly more favorable cost and performance characteristics for renewable energy technologies than are assumed in the reference case, including capital costs that by 2020 average about 15 percent below costs in the reference case, reduced operations and maintenance costs, increased biomass fuel supplies, and higher capacity factors for solar and wind power plants. Fossil and nuclear technology characteristics remain unchanged from the reference case.

Results of the high renewables case suggest that greater technology improvements would accelerate some growth in renewable energy use, primarily after 2015, but would not significantly change the overall dominance of fossil-fueled technologies in U.S. electricity supply. Including cogeneration, total generation from nonhydroelectric renewables is projected to reach 220 billion kilowatthours in 2020 for the high renewables case compared with 148 billion for the reference case (Figure 82), increasing from 3.1 percent of total generation to 4.6 percent. Nearly 50 billion kilowatthours of the difference comes from an additional 12.5 gigawatts of wind capacity (Figure 83) and the remainder from geothermal, MSW, and biomass generation, whereas solar photovoltaic and thermal technologies remain too costly for central station generation.

The increase in renewable energy use in the high renewables case reduces the use of coal and natural gas, lowering carbon emissions from electricity generation by 12 million metric tons (1.6 percent). Retail electricity prices do not change significantly from those in the reference case.

State Mandates Call for More Generation From Renewable Energy

Figure 83. Wind-powered electricity generating capacity in two cases, 1985-2020 (gigawatts)



AEO2000 shows rapidly increasing State requirements to invest in renewable energy technologies. The requirements, reflecting both energy and environmental interests, ensure investment in renewables despite increasingly competitive electricity markets. Renewable portfolio standards, which require increasing percentages of electricity supplies from renewables, are the most common, although other mandates also exist. Requirements differ from State to State, reflecting varying renewable resources, supporting industries, and supply alternatives. In *AEO98,* no quantifiable State mandates existed. *AEO99* projected 2,010 megawatts of renewable capacity additions as a result of State mandates through 2020.

The implementation plans for most State renewable energy mandates are uncertain, and it is difficult to project the effects of renewable portfolio standards in some cases. Nevertheless, for *AEO2000,* it is estimated that State mandates will require additions of 5,168 megawatts of central station renewable generating capacity from 1999 through 2020, including 4,652 megawatts as a result of renewable portfolio standards. The resulting additions are expected to include 2,798 megawatts of wind capacity, 2,162 megawatts of MSW (primarily landfill gas) and biomass capacity, 163 megawatts of geothermal capacity, and 46 megawatts of central station solar (photovoltaic and thermal) capacity. Additions average a few hundred megawatts a year through 2012, needed to meet the increasing requirements. Less than 400 megawatts of renewable generating capacity is expected to be built after 2012, however, to maintain the required shares.